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The Structure of Tax Incentives for

Regulated Electric Utilities

by Duane Chapman*

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Department of Agricultural Economics
Cornell University Agricultural Experiment Station
New York State College of Agriculture and Life Sciences
A Statutory College of the State University
Cornell University, Ithaca, New York, 14853

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*Professor of Resource Economics, Department of Agricultural Economics, Cornell University. Kathleen Cole's earlier analysis of coal plant economics has been very helpful here. Joseph Baldwin provided the graphs. I also wish to acknowledge the assistance of Terry Pagano, Annette Sanford, and Amy Chapman.

CONTENTS

I. INTRODUCTION: THE MULTIPLE BENEFICIARIES OF TAX INCENTIVES

The nation's electric industry has invested $250 billion in plant and equipment since the oil embargo year of 1973. In the early 1980's, 50% of all electric utility investment is for nuclear plant and fuel. In part, this investment program arose because the industry then believed in the 1970's that sales would be 4 trillion kWh this year rather than the current level of 2.5 trillion kWh [1/].

Much of the financing for this expansion has been provided by the tax incentives in the Federal Internal Revenue Code as it applies to electric utilities. These investment incentives were not, to my knowledge, developed with the specific intention of assisting the electric utility industry and its customers, shareholders, lenders, and management. However, the unique capital intensity of this industry has made it a primary recipient of tax incentives [2/].

Customers in normal circumstances can be expected to be the greatest beneficiaries. As explained in section 3, rates can be 25% lower for nuclear power as a direct result of the incentives.

Shareholders benefit from the tax exemption which can fully shelter current dividends from taxation if the company is engaged in a major construction program. This shelter can reach 100% of the current dividend, and is distinct from the dividend reinvestment exclusion [3/].

Lenders benefit from the full deductibility of interest payments. In addition, tax exemption for public bonds provides an incentive for public investment. This is particularly relevant for nuclear power investment.

Management has traditionally viewed tax incentives as another method of borrowing funds for construction programs. These provisions have provided about one-sixth of utilities' new investment [4/]. However, tax incentives do not necessarily increase net income over the life of a facility. Section 7 will show that the tax system causes an efficient plant to operate at a loss over most of its operating life.

Overall, all economic groups associated with utilities have benefited from tax incentives. Indirectly, of course, the tax burden on other tax payers is increased, perhaps by $30 billion annually [5/].

2. PERSONAL MANAGEMENT COMPENSATION, 1975-1982

For 8 years, the Federal Investment Tax Credit maximum rate was 11.5%. The top 1.5% was used to purchase stock for employees, and the major beneficiaries were management [6/]. For example, I estimate that top management at the Long Island Lighting Company received $25,000 to $30,000 each in personal compensation in Federal tax grants for stock as a personal incentive for their decision to construct the Shoreham nuclear plant. While it is improbable that multi-billion dollar decisions were influenced by this personal incentive, the existence of the incentive is of interest. It epitomizes the fact that the overall focus and direction of tax incentives is towards enhanced construction.

3. MAGNITUDE OF TAX INCENTIVES

In this analysis, I am examining the interaction of Federal corporate income taxation with state regulation of electric utilites in order to define the impact of Federal tax policy. The basic tax provisions modelled are: [7/]

1) the investment tax credit, at 10% of construction expenditure

2) the Accelerated Cost Recovery Ststem for accelerated tax depreciation

3) the exclusion of current Allowance for Funds Used During Construction from taxable income, and its rate base inclusion

4) actual interest payment deductibility

5) normalization of tax benefits as required by the Tax Acts of 1981 and 1982

6) air pollution control tax incentives, in section 8 below.

The model analyzes the planning and operating periods for typical coal and nuclear plants from 1980 to 2020. The model utilizes 165 economic and engineering variables, and is described elsewhere [8/].

The representative coal plant is a 625 MWe facility with a rate base value of

$1.12 billion in 1987. It generates 3.3 billion kWh per year. It operates with sulfur removal at 90% efficiency in addition to particulate removal at 99% efficiency. Fuel cost is $1.75 per million Btu for 2.25% sulfur coal. The fuel cost per kWh is 1.9¢, and grows at the overall inflation rate.

The nuclear plant's rate base value is $3.07 billion for a 1000 MWe plant. Specific nuclear fuel assumptions result in a much lower fuel cost per kWh of 0.6¢/kWh which also grows with inflation.

Both plants are financed with 50% debt and 50% shareholders' equity. The interest rate is 15%, and the rate of return on common stock equity is 16%. The major economic values such as specific capital cost, O&M, and nuclear fuel cycle assumptions are listed in the Appendix.

The basic results are summarized in Tables 1 and 2 and Figures 1-3.

Table 1 shows that the average customer cost for a typical coal plant over the life of the plant is 13.4¢/kWh [9/]. This is with the current provisions as enacted in the 1982 Act. The result is a full 5¢/kWh less than would be the case if there were no tax incentives. In magnitude, this means that $165 million annually is transferred from tax revenue to customers for a single plant. The expected tax revenue is an annual $2 million, rather than the $167 million which would be expected in the absence of incentives. Annual revenue is an average $440 million, and annual profit is $114 million.

Extrapolating to our current generation level of 2.5 trillion kWh, we might speculate that the aggregate tax incentive is on the order of $30 billion annually, in 1984 dollars [10/]. This cannot be estimated with any confidence. I would offer $30 billion per year as a value which has equally a 50% chance of being above or below the actual value.

It should be emphasized that the cost and operating data are identical for all three cases in Table 1 and Figure 1. The variations in price arise directly from tax policy. In the Figure, the convergence in the last half of the operating

FIGURE I. TAX POLICY AND CUSTOMER COST
(NEW COAL PLANT WITH SULFUR CONTROL)

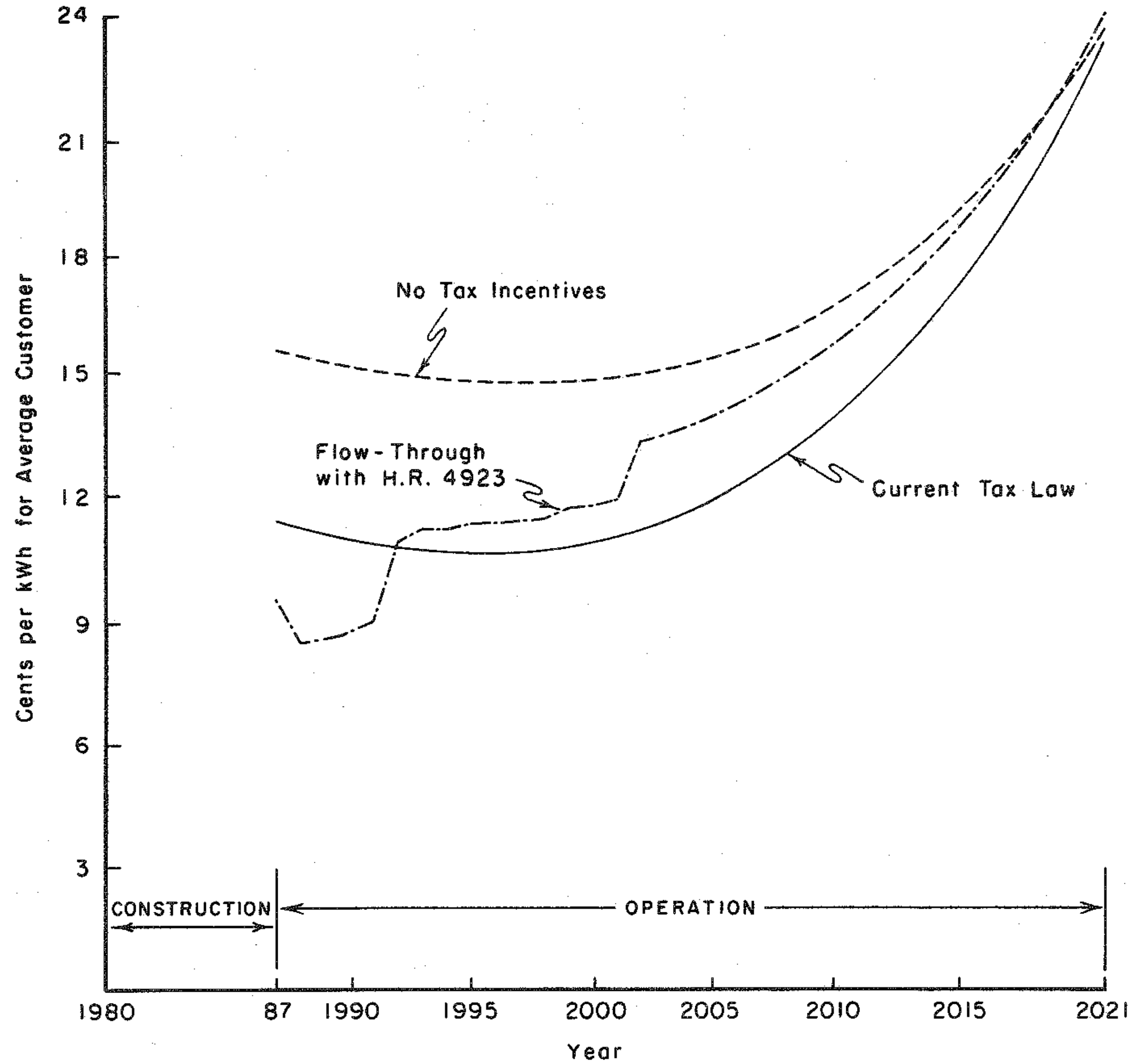


Table 1. Annual Equivalent Costs of Typical Coal Plants with Different Federal Tax Provisions

Tax policies	Customer cost ¢/kWh 1990 dollars	Difference from no incentive case
A. With no tax incentives	18.4 ¢	0
B. With current incentives including normalization	13.4 ¢	5.0 ¢
C. Current tax provisions but with flow-through pricing allowed as in H.R. 4923	12.6 ¢	5.8 ¢

period arises from the assumed inflation in coal and operating costs, and the depreciation of both rate base and tax variables.

Note the variations in initial customer prices in Figure 1. Beginning with the no-incentives case at 16¢/kWh, our current tax system lowers initial 1987 price to 11¢/kWh. H.R. 4923 would further reduce the initial price to 9¢/kWh for states adopting immediate flow-through of tax benefits.

For new nuclear plants, the tax incentive is also equivalent to 5¢/kWh as shown in Table 2.

Viewing both Tables 1 and 2, it is clear that in spite of the present tax incentives, the customer cost of generating facilities being built now is considerably higher than costs from most existing facilities. The national average cost in 1983 was 6¢/kWh.

4. INTEREST EXEMPTION FOR PUBLIC FUNDING OF INVESTOR OWNED NUCLEAR PLANTS

Table 2 also shows the impact of a potential tax incentive which has not previously been available to privately owned utilities. If a privately owned nuclear plant becomes eligible for tax-exempt bonds, its customer cost would decline further to 13.8¢/kWh. Generally, tax exempt utility bonds have yields

Table 2. Annual Equivalent Cost of Typical Nuclear Plants with Different Federal Tax Provisions

Tax policies	Customer cost ¢/kWh 1990 dollars	Difference from no incentive case
A. With no tax incentives	21.6 ¢	0
B. With current incentives for private utilities including normalization	16.4 ¢	5.2 ¢
C. New tax-exempt bonding for private utilities' nuclear plants	13.8 ¢	7.8 ¢
D. Public utility full tax exemption	10.9 ¢	10.7 ¢

or interest rates about 5% below those rates for bonds of private utilities. Such plans now being discussed for the Seabrook and Shoreham plants would further reduce customer costs by an additonal tax incentive. The total of all tax incentives for private utilities with tax-exempt bonding in Table 2 is 8¢/kWh.

5. TAX EXEMPTIONS FOR PUBLICLY OWNED UTILITIES

While the focus of H.R. 4923 is on tax incentives affecting privately owned utilities, it should be noted that the tax incentive for public nuclear plants is greater. Such utilities as the Tennessee Valley Authority, the Sacramento Municipal Utility District and the New York Power Authority are wholly exempt from Federal corporate taxation of the revenue from their nuclear and conventional facilities. In addition, their tax-exempt bonds result in lower interest charges.

Application of the model to these assumptions gives an annual equivalent customer cost of 10.9¢/kWh. The Federal tax loss from a 1,000 MWe publicly owned nuclear facility is $560 million annually.

FIGURE 2. ANNUAL PROFIT TAXATION MOTIVATES EARLY CONSTRUCTION
(TYPICAL NUCLEAR PLANT)
ANNUAL PROFIT, $ MILLION

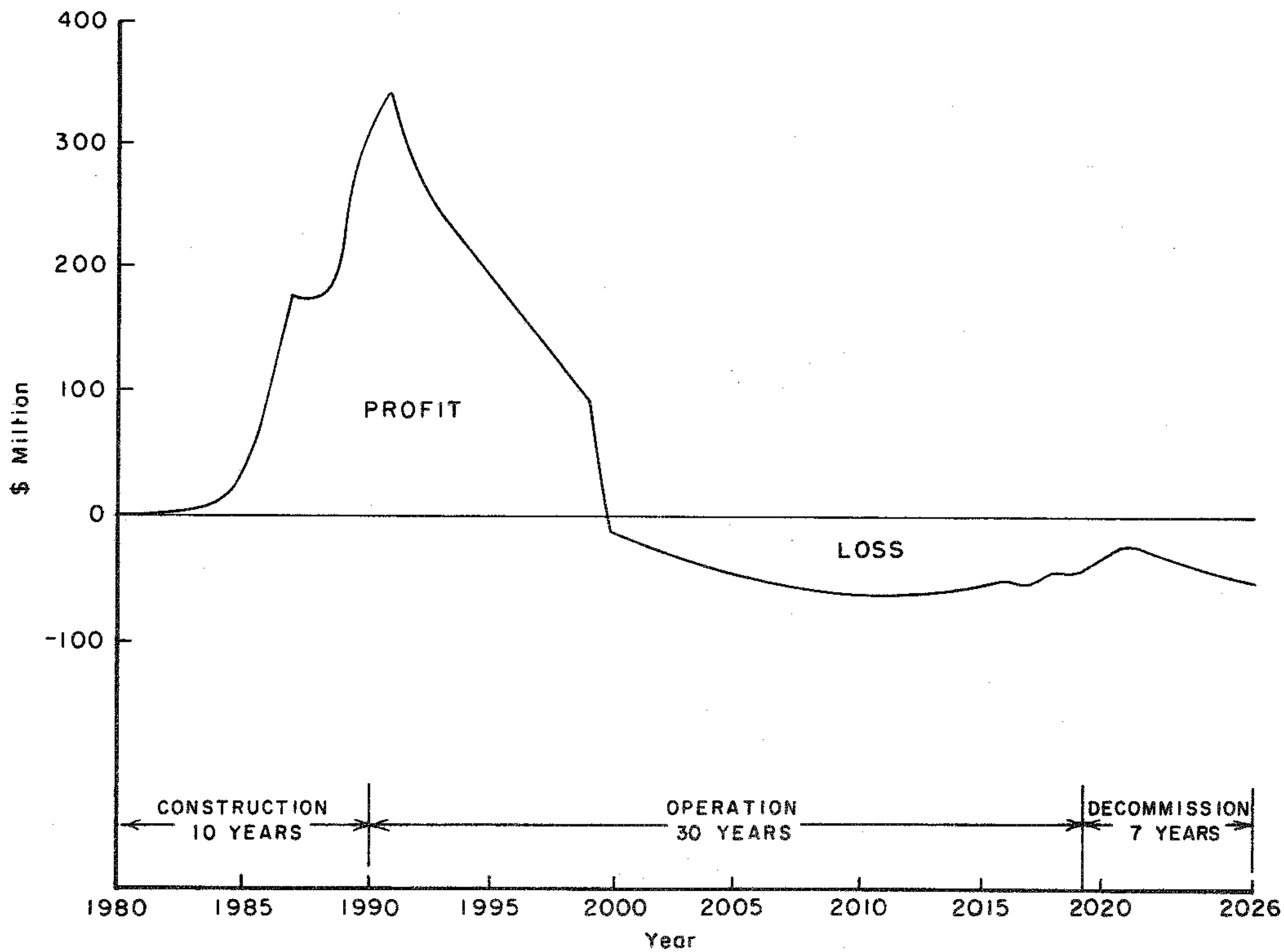
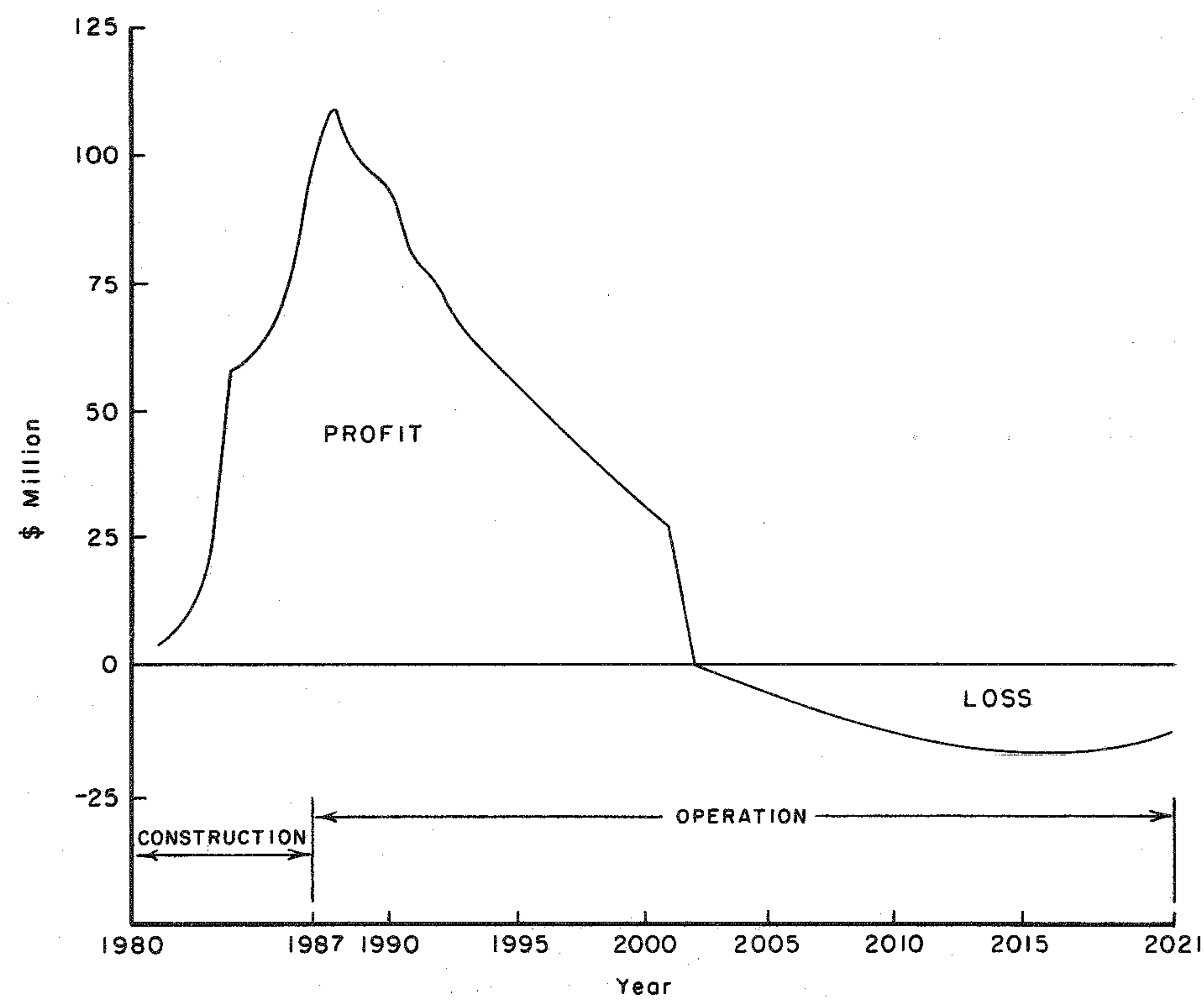


FIGURE 3. ANNUAL PROFIT TAXATION MOTIVATES EARLY RETIREMENT
(TYPICAL NEW COAL PLANT)
ANNUAL PROFIT, $ MILLION



6. PREMATURE CONSTRUCTION INCENTIVE FOR NEW NUCLEAR PLANTS

Because normalization borrows for the company the tax benefits during the construction period and the initial operating years, the time path of profit creates an unusual economic problem for the company. Consider Figure 2 which shows regulated profit as expected to develop over the full 47-year planning horizon for a new nuclear plant. Profit [11/] is considerable during the construction period because of AFUDC credit and tax benefits. In accounting terms, the new plant has earned $1 billion in profit before it begins. Profit continues for several years during operations because of accelerated depreciation.

However, in the final 20 years of operations (2000 to 2019 in Figure 2) profit is negative.

Cash flow has a different picture. It is of course negative during construction, and positive in the initial operating period. However, it becomes negative in the latter half of the operating period as previously collected tax benefits are repaid to customers.

The time path of tax benefits has provided considerable funding for the construction of new nuclear plants. I think it doubtful that new construction would have proceeded at its recent level without this public financing.

7. PREMATURE RETIREMENT INCENTIVE FOR OLD COAL PLANTS

Figure 3 shows a similar profit curve for the typical coal plant. Profit is negative for the last half of the operating period.

Financial incentives, then, point toward building new plants and retiring old plants, and this incentive is separate from considerations of technical efficiency.

Consider a 30 year old coal plant which may have fuel and operating costs of 2.5¢/kWh in 1984. Even if operating efficiently, it can earn little or no profit for its owners. Its rate base has been depreciated, and it is repaying tax benefits. With present regulatory and tax policy, a utility can earn more profit from an unneeded facility than it can from a well-operated plant.

Sponsors of H.R. 4923 may wish to consider allowing state commissions and the IRS to re-define the rate and tax basis for efficient old plants.

Utilities would benefit from earning a profit and tax benefits on efficient old plants, and would be rewarded for operating efficient old plants. Customers would benefit from the much lower costs of operating existing plants.

AIR POLLUTION CONTROL TAX INCENTIVES

FGD (flue gas desulfurization) is one method of attaining acid deposition control. In new coal plants it is treated according to the same rules applicable to the generating components of the plant.

For retrofit FGD on existing plants, the tax incentives are more complicated but comparable [12/]. The flow-through/normalization question seems particularly pointed for the new proposals for Federal funding of utility FGD. The Waxman-Sikorski proposal, as I understand it, makes no reference to this point. Consequently, many states would logically assume that FGD financed by Waxman-Sikorski is comparable to FGD financed by the investment tax credit, and normalize both.

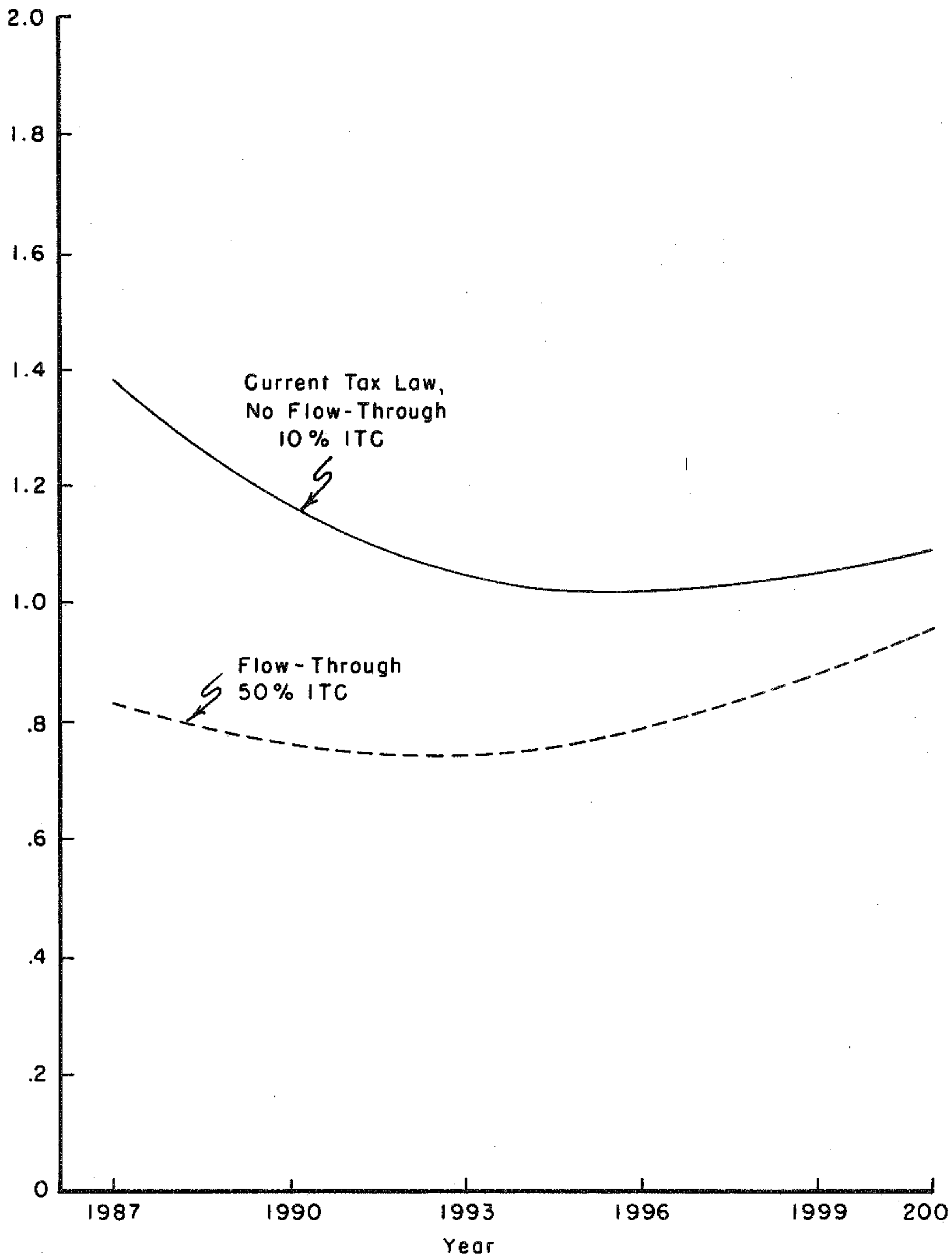
This would give us the anomalous situation in which FGD in Ohio paid for by New York utility customers would nevertheless be rate based, and paid for again by Ohio customers. Presumably, normalization would utlimately repay Ohio customers for the FGD financed by the New York customers.

If FGD investment for acid deposition reduction is financed by public sources such as national funding, tax-exempt bonds, and investment tax credits, there is a much lower proportion of "up front" costs financed by shareholders than is the case for new generating equipment. I think the arguments for normalization are weakest in this context where funding may be primarily public rather than by shareholders.

In Figure 4, flow-through regulation for a 50% investment tax credit on FGD

FIGURE 4. FLOW-THROUGH REGULATION FOR A 50% INVESTMENT TAX CREDIT ON FGD EQUIPMENT

(COST TO CUSTOMERS, ¢/kWh)



reduces initial customer cost form 1.4¢/kWh to 0.8¢/kWh 13/.

9. CONCLUSION: TAX INCENTIVES AND H.R. 4923

The investment incentives in the corporate income tax were not specifically intended to provide unusual assistance to electric utilities. They have benefited investment in all sectors, and are responsible for much of the decline in the importance of the corporate income tax. Hulten finds that for equipment under the 1981 Act until revised, the overall effective tax rate was negative. In their study of industry and asset effective tax rates, Jorgensen and Sullivan found an expected negative tax rate for electric utilities for the proposals embodied in the 1981 Act 14/.

In the early 1950's, the corporate income tax provided 30%-35% of Federal receipts. As investment incentives have developed since 1954, the corporate income tax contribution has declined to 9% of receipts.

However, the normalization requirement embedded in the Economic Recovery Tax Act of 1981 was specific to regulated utilities. Equally specific, the dividend exemption for reinvested dividends is applicable only to public utilities.

The management compensation aspect of TRASOPs in 1975-1982 was industry-wide, but paricularly beneficial to utility management personnel because of their large construction programs.

Taken as a whole, the investment incentive system bears a major responsibility for the present problem of capacity growth exceeding demand growth.

One corollary to this judgement is that nuclear power would not have developed to its present extent without our tax incentive system. Because of its unusually high capital intensity, it receives more investment tax incentives per dollar of annual revenue than any other technology. In the late 1970's and early 1980's, the perceived cost advantage of nuclear power was equivalent in magnitude to the tax incentive difference which existed at that time 15/.

A second corollary result is the financial incentive for the premature construction of new plants, and the premature retirement of efficient operating plants.

These generalizations apply to privately owned electric utilities. Publicly owned utilities and power plants are wholly exempt from corporate income taxation, and also finance expansion with tax-exempt bonds. As a consequence, these direct and indirect tax incentives provide a greater tax subsidy for publicly owned utilities.

H.R. 4923 attempts to remedy these problems related to the private utilities in two ways. It recovers the flow-through option tax benefits for state commissions, and it makes the exercise of this option contingent upon the development of least-cost energy planning.

This least-cost emphasis is an emphasis sorely needed. The standard texts--Kahn, or Phillips, for example [16/]--make no reference to this. Basically, we have assumed that regulation applies to cost-justified rates. Investment decisions have been seen as management responsibility, beyond the domain of regulation.

As a consequence, we see that electric utilities view space heating, for example, as a marketing problem rather than an efficiency problem. If new residences and businesses are to be built with electric resistance heating and modest insulation, utilities have planned to provide the necessary energy with nuclear power.

H.R. 4923 creates a new option, a perspective for the utilities and regulatory commission in a state to develop efficient electric energy supply and use. The contrast between this perspective and cost-justified rate for utility expansion is considerable.

If full competition existed in electricity, neither aspect of the bill would be appropriate. In competitive markets, tax benefits would be flowed-through to customers in order to attain competitive prices.

Similarly, excess capacity would lead to excessive cost in a competitive market and the retirement of the specific companies responsible for such errors.

I view the objectives of the bill as the attainment of efficiency objectives which would normally arise in a competitive industry, but which are presently precluded by our system of tax incentives, rate regulation, and monopoly utility franchises. If this proposal moves into the legislative process, I hope you will consider the three closely linked problems of public financing of privately owned nuclear plants and the attendant tax benefits, publicly owned utilities tax benefits, and the emerging focus on public financing of acid deposition control and its impact on the normalization of tax benefits.

10. FOOTNOTES

1. The industry forecasts from that period are summarized in Science, 17 Nov., 1972, pp. 703-708, and New York Times, May 20, 1984.

2. The Fortune 500 industrial companies average 78¢ in assets per dollar of sales. Electric utilities average $3.10 in assets per revenue dollar. At the low end of the capital spectrum, large retail sales companies average 52¢ in assets per revenue dollar. Data from the 1983 Fortune Directory of Corporations, and the EEI Yearbook.

3. Basically, if the company's tax deductions are sufficient to shelter net income from tax liability, then the dividend itself is said to be "a return of capital," exempt from tax liability. This dividend reinvestment excludes $750 in current utility dividends for individual shareholders and tax payers. Both provisions are subject to future capital gains taxation.

4. D. Chapman, Energy Resources and Energy Corporations, p. 340.

5. See footnote 10 and text.

6. I believe that in 1975 1% of the ITC was available for stock purchases. The additional 0.5% was added in 1976, and required matching employer contributions.

7. The basis for ACRS depreciation is original eligible cost less one-half the amount of applicable investment tax credits. Normalization means that revenues are collected as if tax liability were unaffected by tax benefits in the year in which benefits are received. The company may invest this revenue in new plant and equipment, and return the tax benefit to customers by amortizing it over the life of the facility that creates the benefits.

8. The model is described in D. Chapman, "Federal Tax Incentives Affecting Coal and Nuclear Power Economics," and Nuclear Economics (see References).

9. Unless otherwise noted, annual figures mean annual equivalent amounts. For price, this means a constant annual value which would have exactly the same value as a curve in Figure 1 if the Figure 1 amount were invested at compound interest equal to the shareholders' rate of return. Annual equivalent amount is mathematically identical to the engineer's levelized cost and the accountant's annuity.

10. The 5¢/kWh value and the 13.4¢/kWh customer cost occur in 2008 in Figure 1. In 1984 dollars, the incentive is an illustrative 1.2¢/kWh. For 2.5 trillion kWh, the result is $30 billion.

11. Profit in Figure 2 and in the analysis is defined as pre-tax net income less actual taxes paid.

12. A simplified discussion of pollution control tax incentives is in Williamson's contribution to the URGE Progress Report, and Cole's documentation, and in the Research Institute's Tax Guide for 1984. Tax Incentives vary according to the life of the facility and the use of tax-exempt bonding.

13. This analysis is based upon estimated data for a typical actual coal plant. A 50% reduction in the State SO_2 standards requires a 38% reduction in SO_2 emissions. The plant is 800 MWe, and the FGD installation costs

$130 million in 1984 dollars. Also included are estimates of O&M cost and reduced net generation. Note that a 90% reduction in actual emissions would be about 2.3 times as costly as the Figure 4 data for the 38% reduction.

14. See References: Hulten, and Jorgensen and Sullivan.

15. D. Chapman, "Federal Tax Incentives."

16. See References: Kahn and Phillips. To my knowledge, no economic journal has published an analysis of least-cost electricity production and use.

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12. APPENDIX

Table A-1. Economic Assumptions, 1984 values

1. Capital structure for new plants
   50% debt at 15% interest
   35% common stock equity at 16% after tax-return
   15% preferred stock equity at 15% interest
   AFUDC net of taxes is 10%. Tax-exempt bond rate is 10% where applicable.

2. Construction period
   Nuclear power: 10 years
   Coal plant: 6 years

3. Capacity, electrical
   Nuclear plant: 1,000 MWe
   Coal plant: 625 MWe

4. Capacity factor
   Nuclear plant: rises, stablizes, declines. Average is 60%.
   Coal plant: 60%

5. Operating life
   Nuclear plant: 30 years, 1990-2019
   Coal plant: 35 years, 1987-2021

6. Fuel cost
   Nuclear plant: see Table A-2 (about 6 mills/kWh)
   Coal plant: $1.75/MBtu in 1984, 25.2 MBtu/ton, 2.25% sulfur and 10,600 Btu/kWh

7. Operation, maintenance, insurance, and administration cost
   Nuclear plant: 9 mills/kWh in 1984
   Coal plant: 7 mills/kWh in 1984, including FGD

8. Capital, construction, expenditure in New York
   Nuclear plant: $2,100/kW in 1984 dollars
   Coal plant: $1,400/kW in 1984 dollars

9. Nuclear Decommissioning: $60 million in 1984 dollars or $582 million in 2020-2026.

10. Inflation: 6% per year. No additional real inflation for other factors, except additional 1% real inflation for uranium oxide ore.

11. Taxation: 46% Federal corporate income tax only.

Sources: Atomic Industrial Forum (nuclear O&M), DoE _Projected Costs_, and actual plant data (coal O&M), _Electric Power Quarterly_ (coal cost), Office of Technology Assessment (nuclear capital cost), and actual plant data (coal capital cost). See References.

Table A-2. Nuclear Fuel Cycle Costs, 1984 dollars

Stage	Unit Price
Uranium ore	\$18/lb U_3O_8, 1% real inflation
Conversion	\$5.75/kg U
Enrichment	\$134/SWU
Fabrication	\$150/kg U
Spent fuel transportation and storage	1 mill/kWh, \$149/kg U

Source: Spent fuel cost is 1 mill kWh distributed to 27,100 kg U and a 60% capacity factor for a 1,000 mWe plant. Nuexco exchange value for May was \$18 per pound uranium oxide. Jim Hewlett, DoE, March 1984, Suggests \$134/SWU and 1985 values from DoE *Projected Costs of Electricity*, Vol. 2, p. 56.